Gas-Lift Well Design

Abstract

This white paper describes a unique approach and workflow Petroleum Technology Company AS (PTC) has developed for gas-lift system design.

The workflow employs a combination of proprietary PTC and industry recognised software tools. It allows us to rigorously cater for uncertainties and changes in the reservoir, well and operating conditions over the life of the well.

As a result, our clients are provided with the information they require, to make gas-lift design selection decisions, balancing well lifecycle production optimisation, with well intervention and operability requirements.

Introduction

A large proportion of gas lifted wells around the world are under-performing. Most commonly it is due to ‘multi-pointing’, where instead of all the lift gas being injected via the operating valve at the planned injection depth, some (unintentionally) enters the tubing via one or more of the shallower unloading valves. In other cases, wells may underperform as the planned injection depth cannot be reached with the available lift gas pressure.

These issues are often the result of unloading valve reliability problems or inadequate gas-lift design. The unique architecture of PTC’s unloading valves delivers significant functionality and reliability benefits. These benefits are fully described in a separate white paper [1]. Another common reason for underperformance, and in particular unloading valves not performing as expected, is a lack of rigour, during the traditional gas-lift system design process. This is because it often doesn’t cater for the inevitable uncertainties and life of well changes commonly encountered.

PTC have therefore developed a unique gas lifted well design workflow, which employs a combination of proprietary and industry recognised software tools. The workflow is described in this white paper. It allows us to rigorously cater for uncertainties and changes in the following parameters over the life of the well including (and not limited to):

- Reservoir properties: pressures, productivity indices, watercuts and gas oil ratios.
- Operating conditions: flowing tubing head pressure, lift gas pressures and volumes.
- Well kill and treatment fluid properties.
- Completion and intervention constraints.

These uncertain and changing design parameters, mean that in many cases, there is no single unique design solution. Instead, a design is refined and selected (in conjunction with the client) from various options considering:

- Production optimisation
- Completion complexity
- Well operability and flexibility

Thereafter, the recommended design is ‘stress checked’. This is to ensure that, despite any compromises that may have been made, it is robust (principally that kick-off is always possible, and unloading valve multi-pointing / check valve chattering is always avoided) under the range of anticipated operating scenarios. The propensity for common oilfield scale deposition at the valve setting depths can be checked, and a well unloading schedule can be produced.

Unloading Valve Operation

Since many gas-lift performance issues are associated with unloading valves not functioning as planned, an outline of unloading valve operation is described in this section.

Unloading valves are installed in cases where the lift gas compressor cannot supply sufficient pressure to facilitate immediate deep lift gas injection or in cases where you have to displace a heavy completion fluid out of the well. They are installed in the well at depths, which are selected during the design process, to facilitate temporary shallow, then sequentially deepening gas-lift injection during well commissioning. Once the lift gas reaches the planned depth of injection (the operating valve) the unloading valves are designed to close and remain closed under normal producing conditions.

The unloading process is illustrated in Figure 1.

- The red lines represent the gas gradient in the annulus
- The broken blue line represents the initial pressure gradient of fluid in the tubing. It can be seen that initially, gas can only pass from the annulus to the tubing via the shallowest unloading valve
- The blue line represents the pressure gradient in the tubing once gas has been injected and steady state production conditions are achieved

Once the lift gas reduces the density of the fluid in the tubing above the shallowest unloading valve, the pressure gradient in the tubing below the shallowest valve (second diagonal red line) falls to a level that allows lift gas to pass through the next unloading valve.

At this point, the lift gas injection pressure is reduced so the shallowest valve closes, and the process is continued until the desired injection depth is reached.

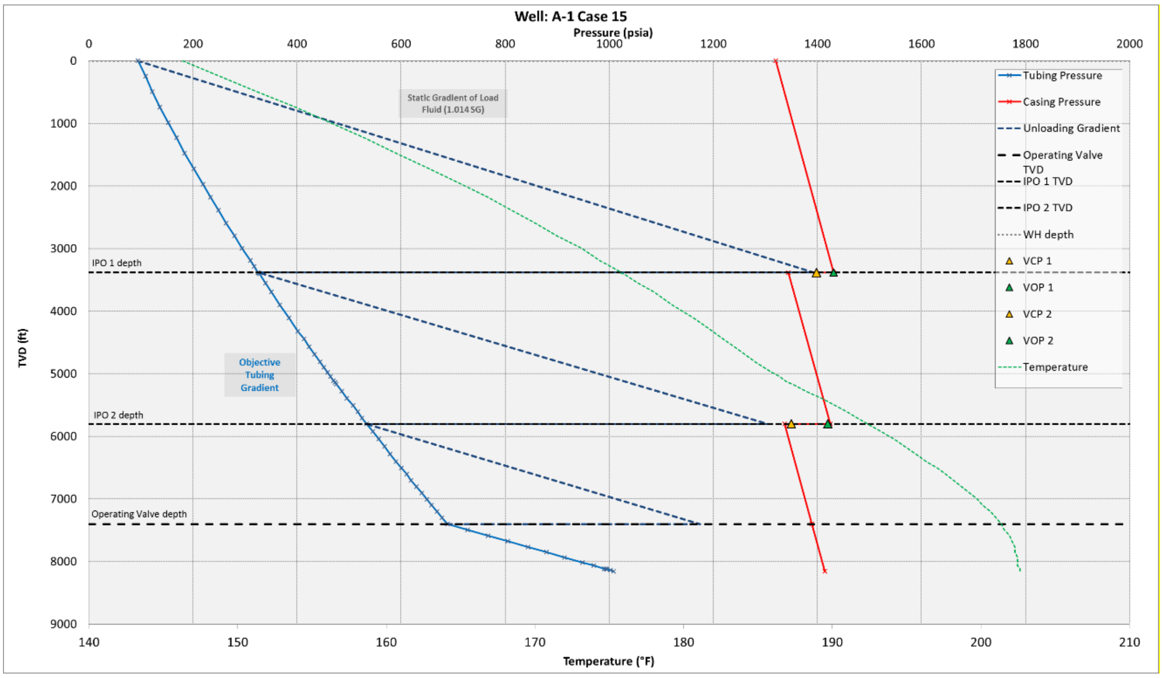

Figure 1: Design Plot

Most commonly, Injection Pressure Operated (IPO) unloading valves are used. The opening and closing pressures of IPO unloading valves are controlled by a force balance across an N_2 charged bellows see Figure 2.

If the closing force from the 'dome' side of the bellows due to the N_2 charge pressure is less than the opening forces exerted on the valve tip and external surface of the bellows, then the IPO unloading valve either moves to the open position. If the closing force from the 'dome' side of the bellows due to the N_2 charge pressure is greater than the opening forces exerted on the valve tip and external surface of the bellows, then the IPO unloading valve either moves to the closed position.

N.B. when the valve is in the open position, the (annulus) lift gas injection pressure is applied across the whole bellows cross-sectional area; the closing pressure is then equal to the N_2 charge pressure. The opening pressure is always greater than the closing pressure since the effective bellows area is reduced by an amount equal to the valve port opening area.

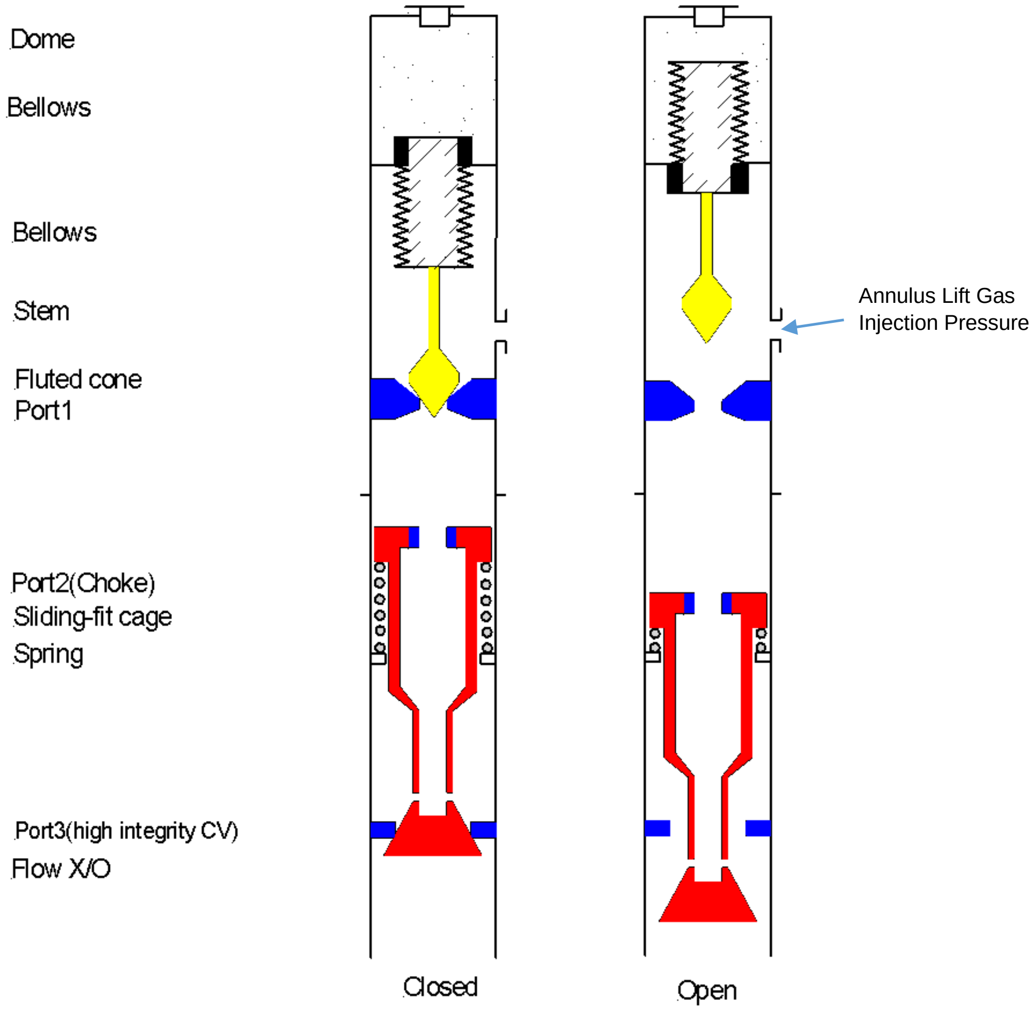

Figure 2: IPO Layout

This is important because, along with the bellows hysteresis effect, it results in a difference or 'spread' between the opening and closing pressures. The casing pressure drop required to close each successive IPO unloading valve, is equal to the spread.

Because it is tubing pressure that is applied to the valve tip when opening, the opening / closing pressure 'spread' will be affected by any changes in the magnitude of the tubing pressure over the life of the well. Changes in the well temperature at valve depth will also affect the dome pressure and therefore have an impact on the spread.

Consequently, in contrast to common industry practice, where an arbitrary spread value is often used, PTC rigorously calculate the spread at all expected well lifecycle conditions.

Individual IPO unloading valve N_2 charge 'dome' pressures are also specified accordingly. A safety factor is also applied to the injection pressure reduction when transferring from the deepest IPO unloading valve to the operating valve, providing further assurance that the deepest (and by default any shallower) IPO unloading valves remain closed after unloading is completed.

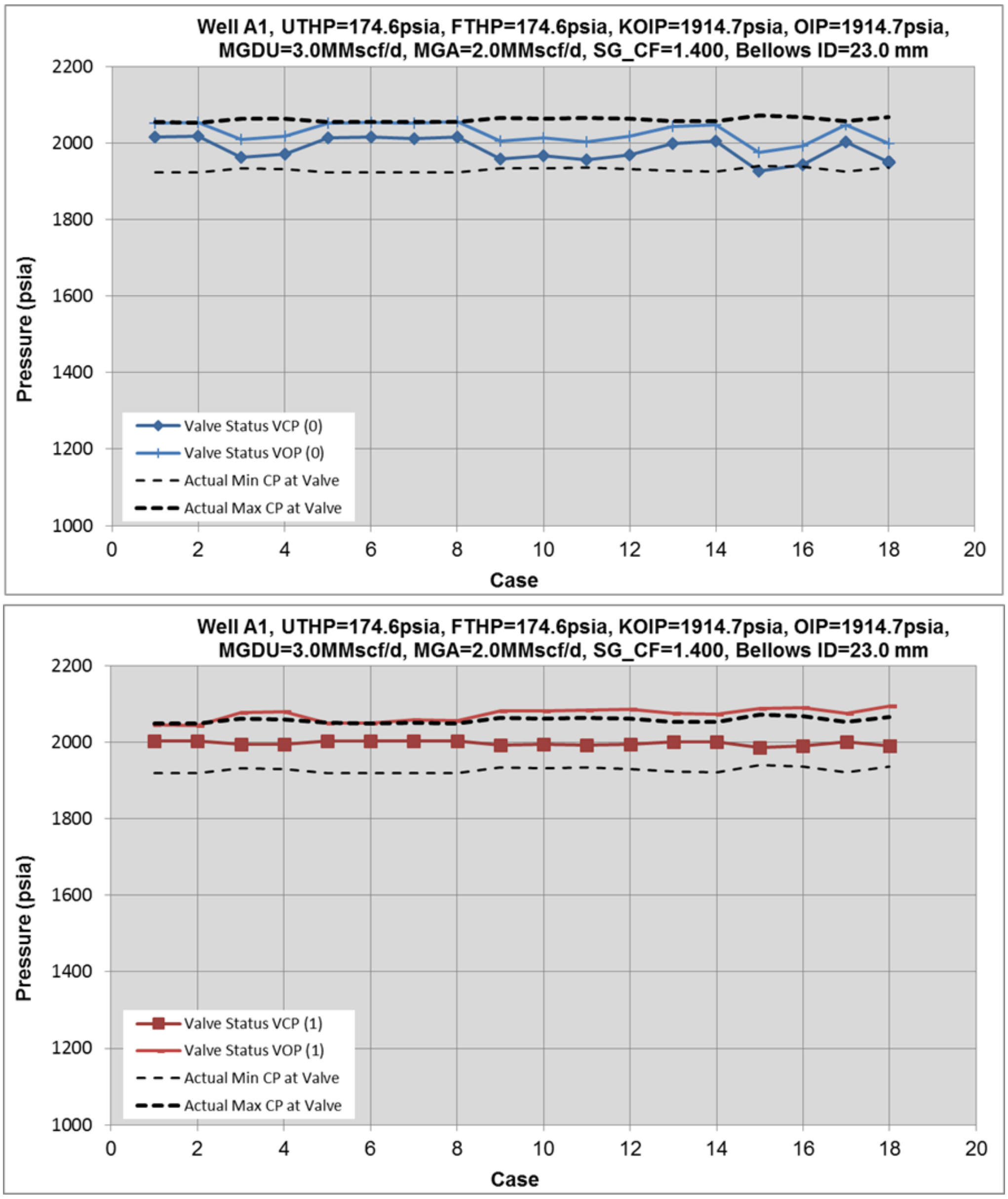

Figure 3: Valve Status over LoF

Figure 3 represents an additional check that PTC performs to determine the status of IPO unloading valves over all the supplied field cases, once the design case has been selected. As the nitrogen charge in a gas-lift valve is influenced by temperature the opening and closing pressure of the valve will also be subject to changes depending on which scenario and temperature is encountered. It is therefore important that this is identified during the design process to ensure the risk of multi-pointing is significantly reduced and to allow PTC to adjust the Casing Head Pressure (CHP) drop accordingly.

A safety factor is commonly applied to the available lift gas pressure. This mitigates the most common sources of error in gas-lift designs; over optimistic assumptions regarding lift gas pressure and variations in temperature.

As a result, the likelihood of PTC unloading valves failing to either open or close at the expected lift gas injection pressures, is significantly reduced. Any outlying cases encountered would be discussed with the client.

Gas-Lift Design Workflow

The PTC gas lift design workflow is an iterative process, with client input and discussion at key decision points throughout.

Step 1: Data Gathering

The first step is to gather the design input data and assumptions. An input data sheet is supplied to the client. It is used to document the range of possible parameters that the design will have to cater for throughout the life of the well including:

- Reservoir pressures and productivity indices
- Produced fluid and lift gas properties
- Well architecture and deviation data
- Well kill and treatment fluid properties
- Well operating pressures and temperatures

This data is ‘sense checked’ and any uncertainties clarified with the client before a set of design cases are jointly defined.

Commonly within the industry, a gas-lift design workflow included only one or two ‘worst case scenario’ design cases. Industry experience has shown that this does not deliver the rigour needed to assure the optimum design. The PTC approach is to typically defined around 21 separate design cases.

Case/Date	Pres (psig)	PI (stb/d/psi)	GOR (scf/stb)	WC (%)	Max operating liftgas available (MMscf/d)	Max liftgas available during unloading (MMscf/d)	Max Liftgas supply pressure under operating conditions (psig)	Max Liftgas supply pressure at kickoff (psig)	Lift gas SG	UTHP (psig)	FTHP (psig)
Aug-15	2877	59.5	711.3	0						1003	
Mar-16	2857	50.2	700.8	1						976	
Nov-16	2868	43.2	709.9	28						932	
Jul-17	2872	43.4	716.1	48						912	
Mar-18	2872	43.8	718.6	60						900	
Nov-18	2869	44.9	719.3	67						886	
Jul-19	2864	46.2	718.1	73						892	
Mar-20	2859	47.0	717.6	76						892	
Nov-20	2855	47.7	718.0	79						884	
Jul-21	2851	48.4	718.1	82						878	
Mar-22	2847	49.0	718.0	83	5.0		1595.2		0.670	872	
Nov-22	2842	49.6	717.7	85						868	
Jul-23	2838	50.1	717.4	86						864	
Mar-24	2834	50.6	716.9	87						860	
Nov-24	2829	51.0	716.5	88						858	
Jul-25	2825	51.4	716.0	89						855	
Mar-26	2820	51.8	715.4	89						853	
Nov-26	2816	52.2	714.8	90						851	
Jul-27	2812	52.5	714.1	90						849	
Mar-28	2807	52.8	713.5	91						847	
Nov-28	2803	53.0	712.7	91						845	

Table 1: Sensitivity Profile

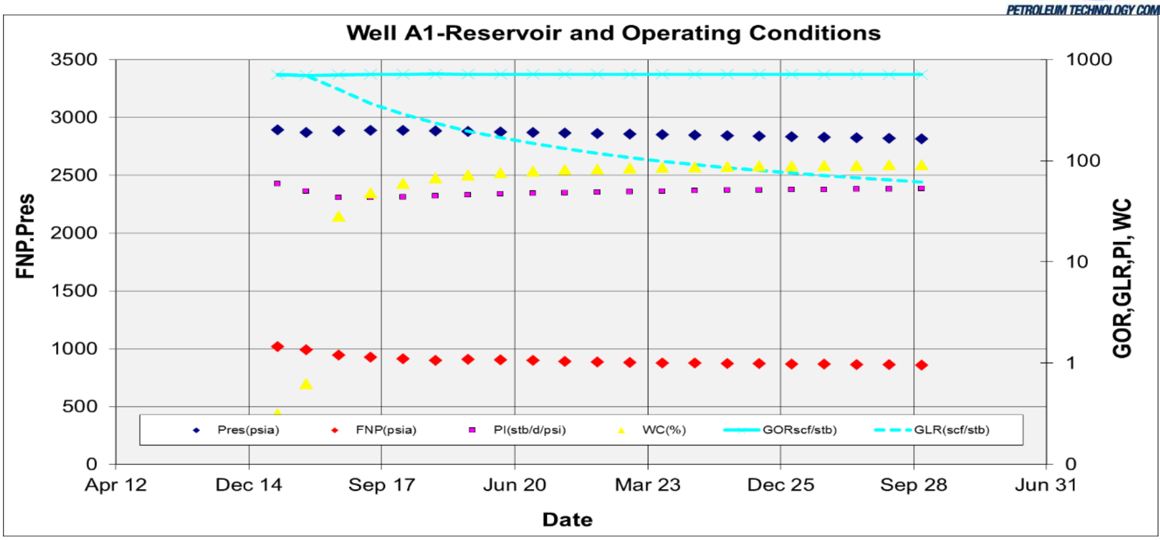

Figure 4: Sensitivity Profile Cases

Table 1 and Figure 4 shows a range of 21 'time step' design cases (refined from a reservoir engineering profile of 163 data points as shown in Figure 5) defined for a well, where various operating parameters are expected to change significantly over the life of field (LoF).

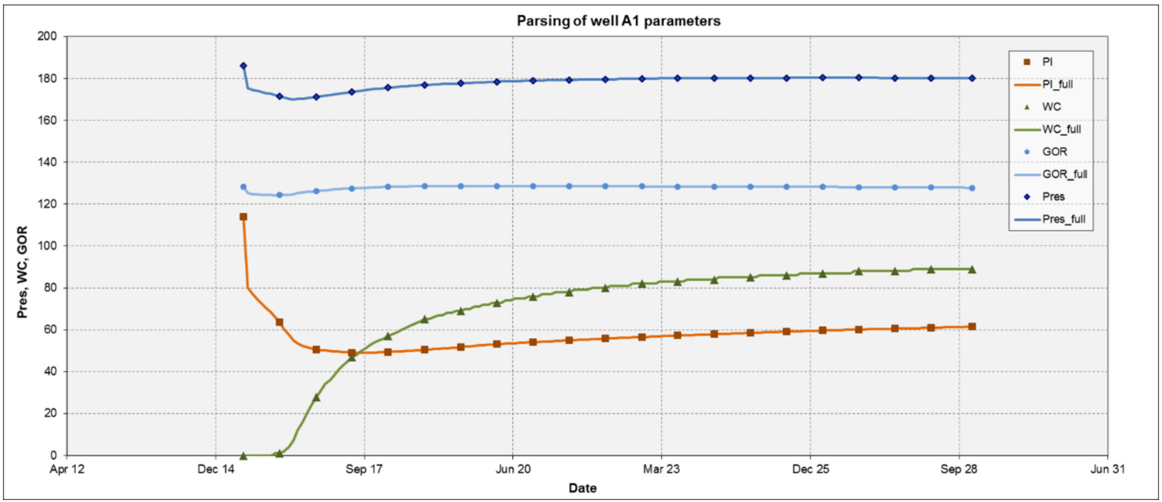

Figure 5: Filtered Profile Cases

Step 2: Gas-Lift Performance Envelope Generation

This step involves the determination of gas-lift and natural flow performance envelopes using Prosper well simulation software plus PTC proprietary code. This is a necessary precursor to the rigorous gas-lift design described in the following sections. At this stage, a simple fixed point gas-lift injection model is used.

These performance envelopes facilitate the identification of the design decisions, which will have the greatest (and least) impact on well performance. They also assist in quantifying the impact of any compromises, which inevitably will have to be made to the final design selection.

An example of the deliverables from this step, are shown in Figures 6 – 8. In this example, based on the data set given in Table 1, the predicted oil rates are plotted for each of the 21 design cases.

In Figure 6, the impact of lift gas injection rate is shown. In this case it can be seen that the well will initially flow naturally, then require gas-lift to flow.

This information, regarding cases where natural flow is possible, is often very important to understand when selecting a final design. It may be that in order to have a design that works over the widest possible range of cases, a compromise has to be made where a decision to maybe use gas-lift to kick-off the well but then flow naturally for a period of time is optimal.

It can also be seen that in most cases there is little benefit in attempting to gas-lift with more than 5 MMscf/d lift gas volume.

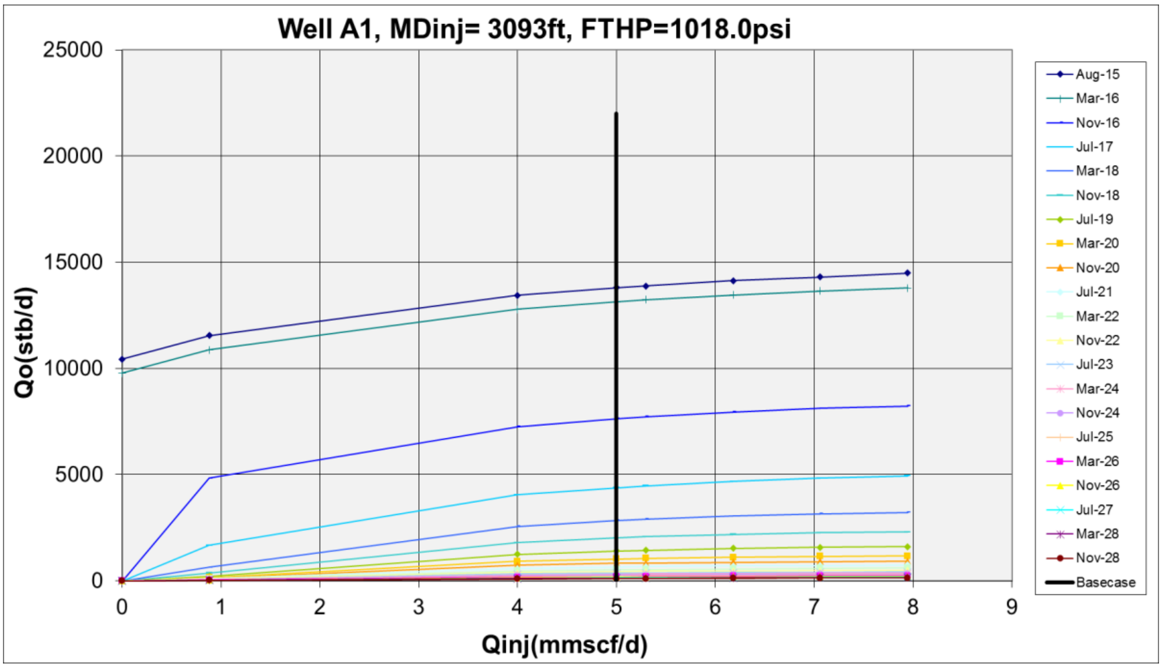

Figure 6: Gas-lift Rate Sensitivity

In Figure 7, the impact of lift gas injection depth is shown. This can be useful when for example, assessing the impact of adding or eliminating a valve setting location to or from the design.

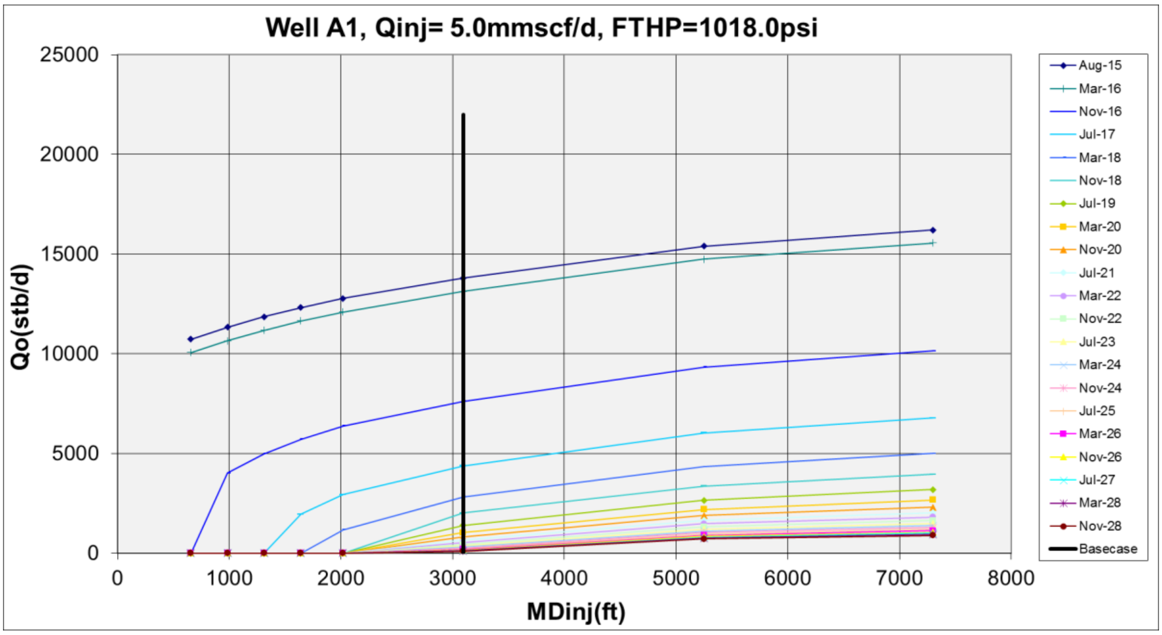

Figure 7: Depth of Injection Sensitivity

In Figure 8, the impact of FTHP is shown. It can be seen that, in this case the oil production is very sensitive to FTHP.

This can have an impact when selecting a well routing / operating philosophy, e.g. if the option exists to route the well to a low pressure separator. It can also help assist Petroleum Engineers when looking at a well allocation/field optimisation strategy.

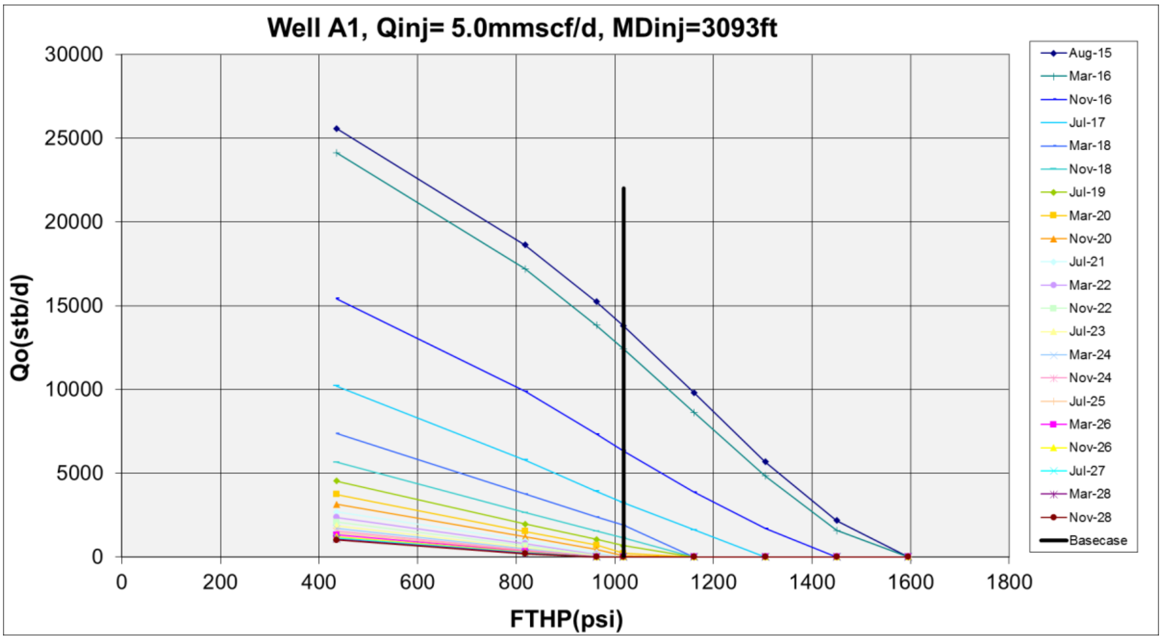

Figure 8: Reduction of THP Sensitivity

Step 3: Gas-Lift Valve Depth Selection (1st pass)

In step 3, the PTC gas-lift design software is used in conjunction with 'Prosper' well simulation software, to establish and refine the designs for each for the defined cases.

Specifically, the depths at which unloading and operating valves should be optimally located for the cases supplied.

An example of the deliverables from this step are shown in Figure 9, which at each time step illustrates the predicted:

- Shallowest valve depth (dark blue line)
- Deepest valve depth (pink line)
- Deepest gas-lift point (yellow triangle)
- Natural flow oil production (green bar)
- Gas lifted oil production potential (blue bar)

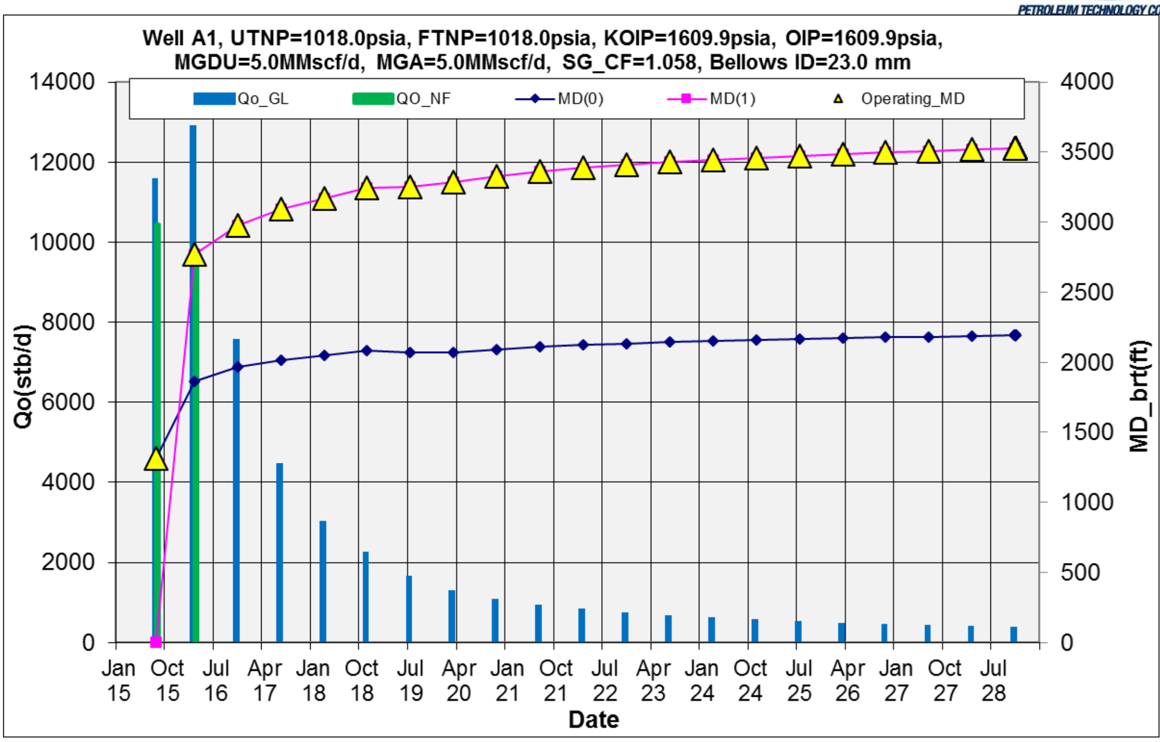

Figure 9: Predicted Well Performance and Operating Point for LoF

Initially in case 1 it can be seen that:

- Gas-lift benefit vs natural flow is marginal
- The maximum lift gas injection depth would be approximately 1300 ft (MD brt)
- There is no need for an unloading valve (operating valve only)

However by case 3 it can be seen that:

- The well will not flow naturally
- Lift gas can be injected as deep as 2900 ft
- Both unloading and operating valves are needed

In subsequent years it would be possible to inject progressively deeper for optimal production.

At this point the fundamental gas-lift design decision has to be made (along with the client) regarding the number of unloading valves to be run and the depth at which they should be set.

Step 4: Gas-Lift Valve Depth Selection (2nd pass)

In step 4, we test the well performance using scenarios with 1 or 2 IPO unloading valves. An example of the deliverable from this step is shown in Figures, 10-12. The legends in Figures 10 and 11 are as described for Figure 9.

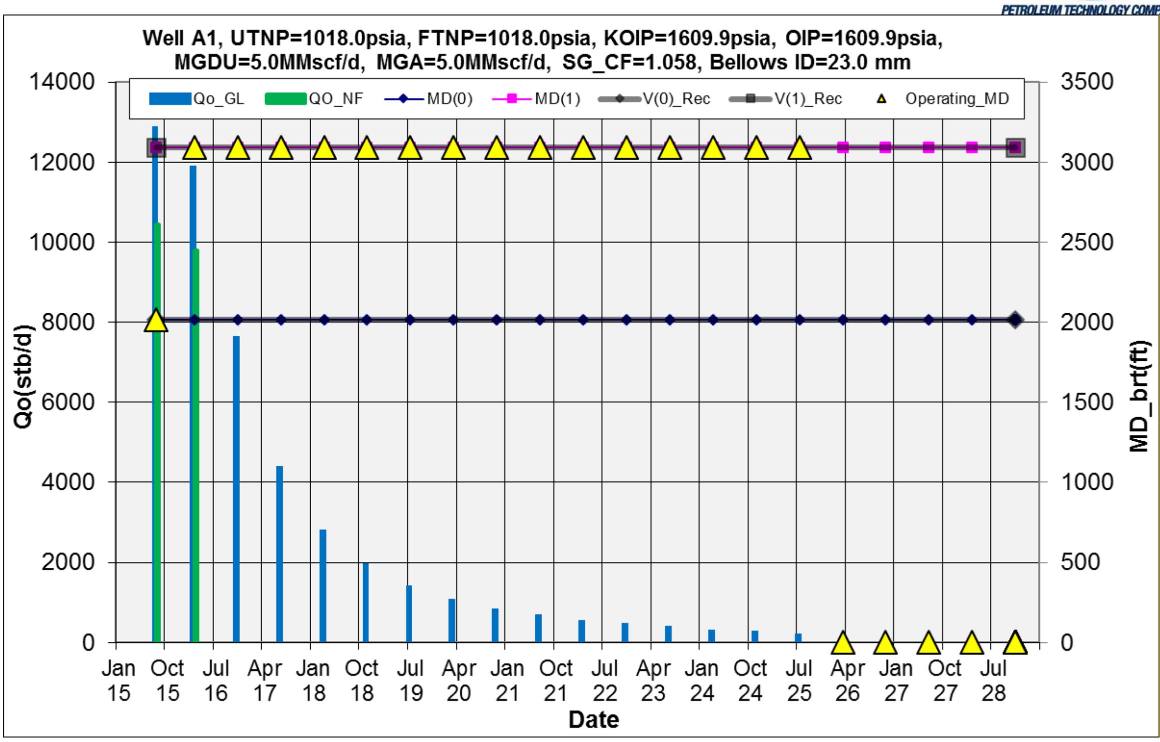

Figure 10: Well Performance and Operating Point for LoF (2 Valve design)

Figure 10 shows a 1 x unloader, 1 x operating valve design option. It can be seen that with this option deep gas-lift is not initially feasible (case 1, yellow triangle).
In this scenario, our clients' have to assess the pros and cons of a well intervention to change the depth of injection after 6 months production, vs. using gas-lift to unload and kick off the well then flow naturally until gas-lift was possible at case 2. N.B gas lifted production post 2025 is not possible.

Alternatively, the unique PTC approach; using unloading valves as temporary operating valves [1] could be utilised. It should be noted that this approach requires a larger 'spread' pressure, so the maximum injection depth with 2 valves would therefore be reduced. Contact PTC for further details.

Figure 11 shows an alternative 2 x IPO unloader, 1 x operating valve design option. It can be seen that with this option 2 interventions are needed to optimise the depth of injection. During cases 1 and 2 only shallow injection is possible (well can naturally flow), intermediate injection is possible in cases 3 and 4 before the maximum depth of injection can be achieved thereafter. In this option, gas lifted production is possible beyond 2025 through to 2029.

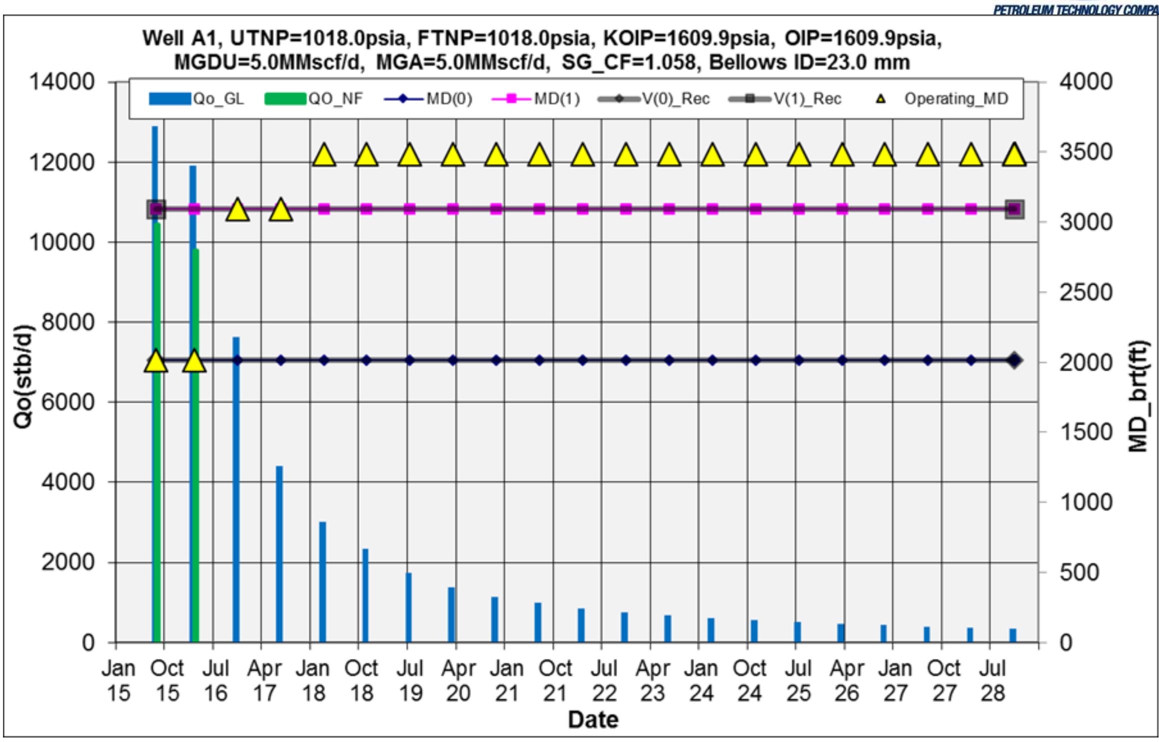

Figure 11: Well Performance and Operating Point for LoF (3 Valve design)

In Figure 12, the production impact of these options are illustrated. It is interesting to note that initially the 3 valve design delivers marginally less daily production. Thereafter, it is noteworthy that a seemingly small incremental benefit late in field life can have such a large cumulative impact. Approximately 1.2 million stb, delivering considerable additional revenue.
This particular scenario, where a design that appears to be sub-optimal at initial start-up conditions will however later become optimal, is very common. In many cases data uncertainty makes the selection of an optimum solution even more challenging. On occasion it can also be the case that a design that appears to be optimum at initial field conditions can actually prove to be not suitable for later conditions and this is why it is prudent to undertake a full life of field design approach to assess the gas lift performance over all conditions.

It should be noted however that neither of these cases can deliver the cumulative production potential predicted at step 3 (figure 9), which assumed different valve depths in each case. This would require many different lift depths and moving unloading valves, operating valves and dummy valves as necessary over time to optimise production. This would not be practical even on land wells where intervention costs are relatively low.

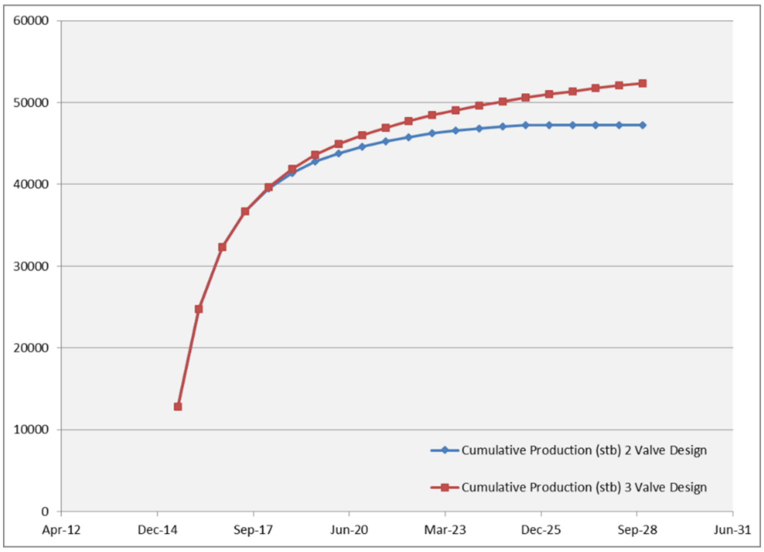

Figure 12: Comparative Cumulative Production

Consequently a compromise usually has to be made considering instantaneous and cumulative production along with completion complexity and operational feasibility. This type of information and the supporting analyses, is therefore fundamental to our client making informed decisions regarding the optimum valve numbers, valve spacing, and intervention strategy.

At the same time we can also perform sensitivity analyses, to look at other field development scenarios. For example, looking at the impact of different lift gas or separator pressure options.

Step 3 /4 (a): Monte Carlo probabilistic analysis

Where significant well data uncertainties exist, PTC adopts a Monte Carlo (MC) probabilistic approach to selecting valve setting depths. The approach requires that minimum, maximum and mean values of the principal variables are input. An example is shown in table 2. In common with reservoir engineering MC analyses, triangular distributions are used.

Min PI(m3/d/bar)	Mean PI(m3/d/bar)	Max PI(m3/d/bar)
5.81	6.46	7.10
Min Pres(bara)	Mean Pres(bara)	Max Pres(bara)
336.00	373.33	377.06
Min GOR(m3/m3)	Mean GOR(m3/m3)	Max GOR(m3/m3)
145.92	162.14	178.35
Min WC(%)	Mean WC(%)	Max WC(%)
0	2	90

Table 2: Monte Carlo Analysis

Typically 10-20000 separate design simulations are then carried out using random combinations of these data. Typical deliverables from this step are as shown in figure 13.

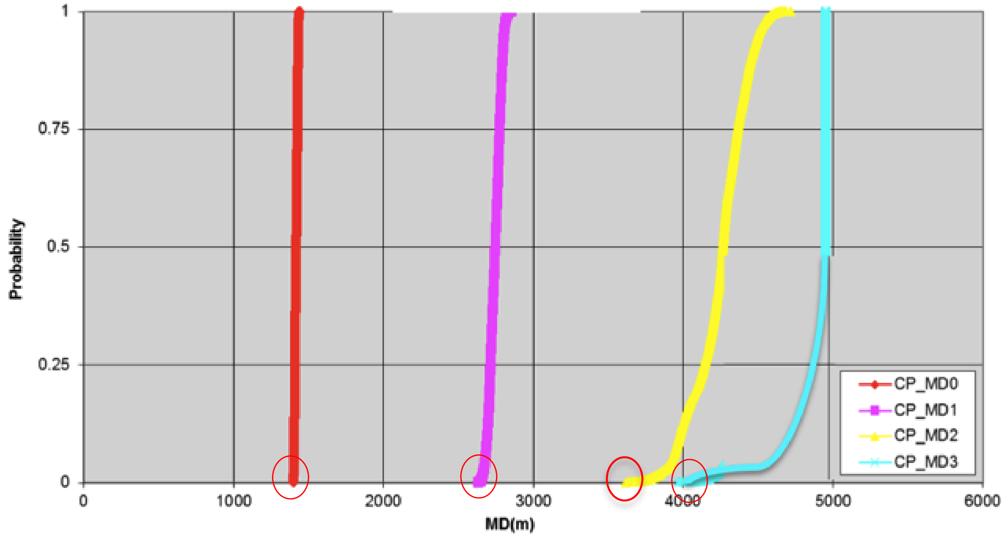

Figure 13: Monte Carlo Deliverables

Figure 13 indicates that for this particular example in 100% of the cases analysed it would be possible to unload from 1300, 2600, 3550 m and gas-lift through an unloading valve set at 4000 m. It also indicates that in 50% of the cases analysed, it would be possible to gas-lift from 5000 m (the maximum possible depth in this example data set).

This approach provides our clients with confidence when selecting valve numbers and setting depths, in cases where significant data uncertainty exists.

Step 5: Unloading Valve Specifications

Once a decision regarding the number and location of IPO unloading valves is reached, a primary design case is selected. Usually, this is the one identified in step 4, where the required lift gas volumes are highest, as this will be the most demanding case. This time we establish unloading valve N_2 charge pressures and port sizes for the selected valve depth configuration. N.B. PTC policy on minimum port size to avoid blockage is 10/64".

The PTC proprietary software is then used to re-check the status of <u>all</u> of the unloading valves, for <u>all</u> (in this case 21) of the design cases. This is to ensure that multi-pointing will be avoided, and that kick off will be possible, in each of the cases, with the valves set up as specified in the primary design case.

This approach is, we understand, unique to PTC. It further assures confidence in design reliability throughout field life.

Step 6: Orifice Sizing and Flow Stability

Flow instability can have a significant impact on production rates. It can also cause production facility management challenges.

Following the onset of unstable flow, a poorly designed gas-lift system can exacerbate the situation, by delivering fluctuating gas rates in response to fluctuating well pressures.

To avoid this, ideally both the completion (if possible) and the gas-lift operating valve need to be appropriately sized and specified, considering the expected life of well operations. In particular gas flow through the orifice in the gas-lift operating valve should ideally be in critical (supersonic) flow.

PTC offer 3 orifice types [1]:
- Industry standard square edge orifice
- Industry standard Venturi orifice
- Proprietary 'Stealth' Venturi orifice

In order to operate in critical flow, a square edged orifice requires to drop approximately 50% of the upstream pressure, whereas a Venturi orifice requires to drop only approximately 10 – 15% of the upstream pressure.

PTC proprietary software is used to check whether critical flow can be achieved for all design cases using a square edged orifice or if a Venturi orifice would be required.

Figures 14 - 16 show the deliverables from this stage. In Figure 14 the green squares are the predicted life of well operating points (tubing pressure at the valve) superimposed on the square edge orifice performance diagrams.

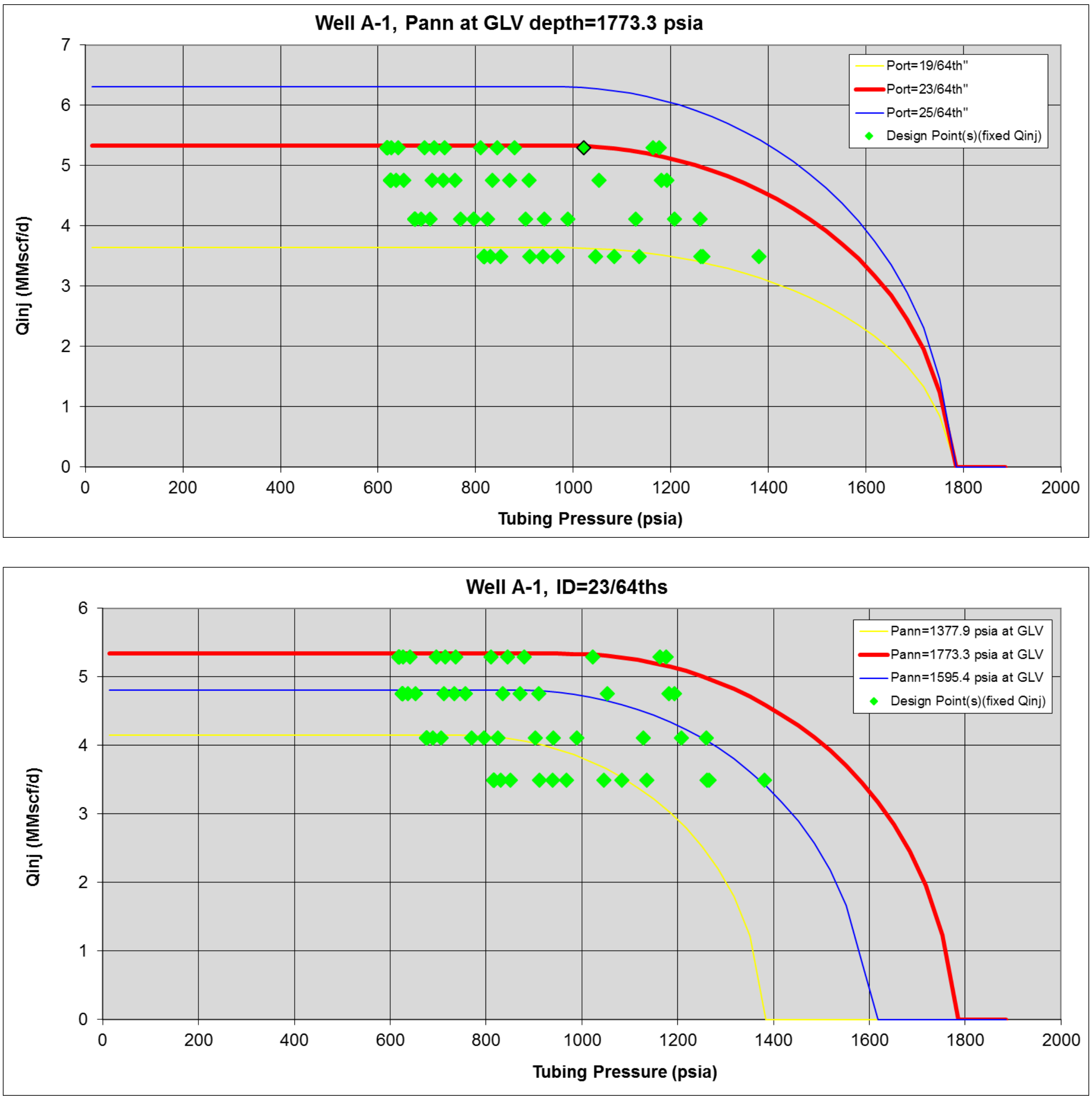

Figure 14: Orifice Performance Characteristics

In Figure 14 the upper plot shows the lift gas flowrate that could be delivered through different orifice sizes at a fixed annulus pressure. The lower plot shows how the lift gas flow rate varies (for a given orifice size) if the annulus pressure is varied.

In each case, some of the operating points are close to the right of or below the critical flow region (where lift gas delivery rate is sensitive to tubing pressure); i.e. it operates in the non-critical (subsonic) region. If a critical flow scenario exists the rate is unaffected by changes to tubing pressure and is a desirable gas lift situation to design for to yield stable performance.

In figure 15 the Venturi, orifice performance diagram is superimposed. It can be seen, for this example, that the lift gas flow rate is predicted to be stable at 5.3 MMscf/d at all expected tubing pressures (at the valve depth).

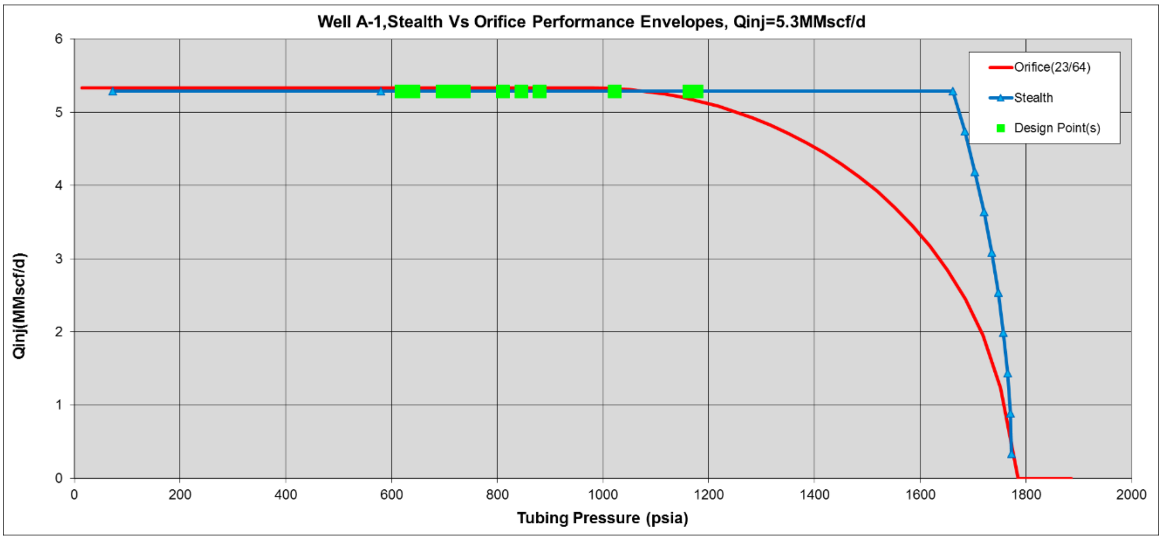

Figure 15: Venturi and Square Edged Orifice Comparison

At first glance this might suggest the Venturi orifice should be favoured. However the Venturi orifice is less flexible, where there is a requirement to deliver less lift gas to a particular well as is often the case for initial conditions.

In figure 16 the relatively narrow lift gas delivery rate ‘turn down’ range is illustrated. It can be seen that for the predicted life of well operating points, critical flow through the Venturi orifice for all cases can only be assured down to approx. 4 MMsdf/d. Below that rate some of the operating points are predicted to be to the right of the critical flow operating region.

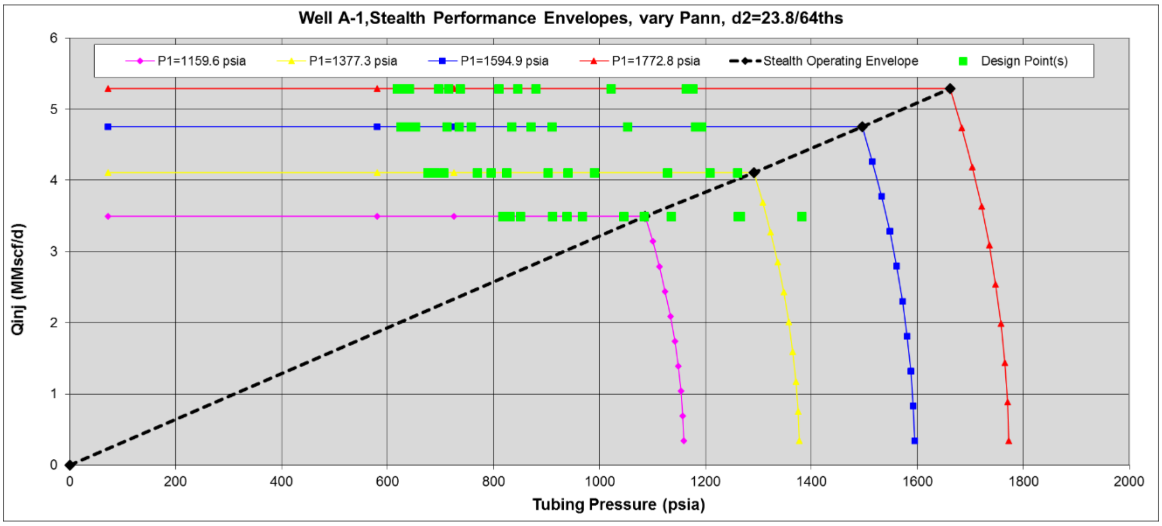

Figure 16: Venturi Orifice Rate Capability

Referring again to Figures 15 and 16. It can be seen that although the square edged orifice is predicted to operate in a region closer to sub-critical flow, the predicted changes in lift gas flow rate, in response to changes in tubing pressure are much less severe than in the case of the Venturi orifice (in sub-critical flow).

Once again there is a compromise decision to be made. This time between flow stability assurance and flexibility to adjust lift gas rates over a wide ‘turn down’ range. The information the PTC approach provides to clients is critical in facilitating this decision.

PTC have also, on numerous occasions, provided our clients with advice regarding tubing sizing from a life of well perspective as shown in Figure 17. This has often resulted in significant instantaneous and predicted lifecycle production gains as well as assuring improved flow stability. The below figure is an example of the oil production gain for both natural flow and gas-lift of moving from 3 ½” to 4 ½” tubing.

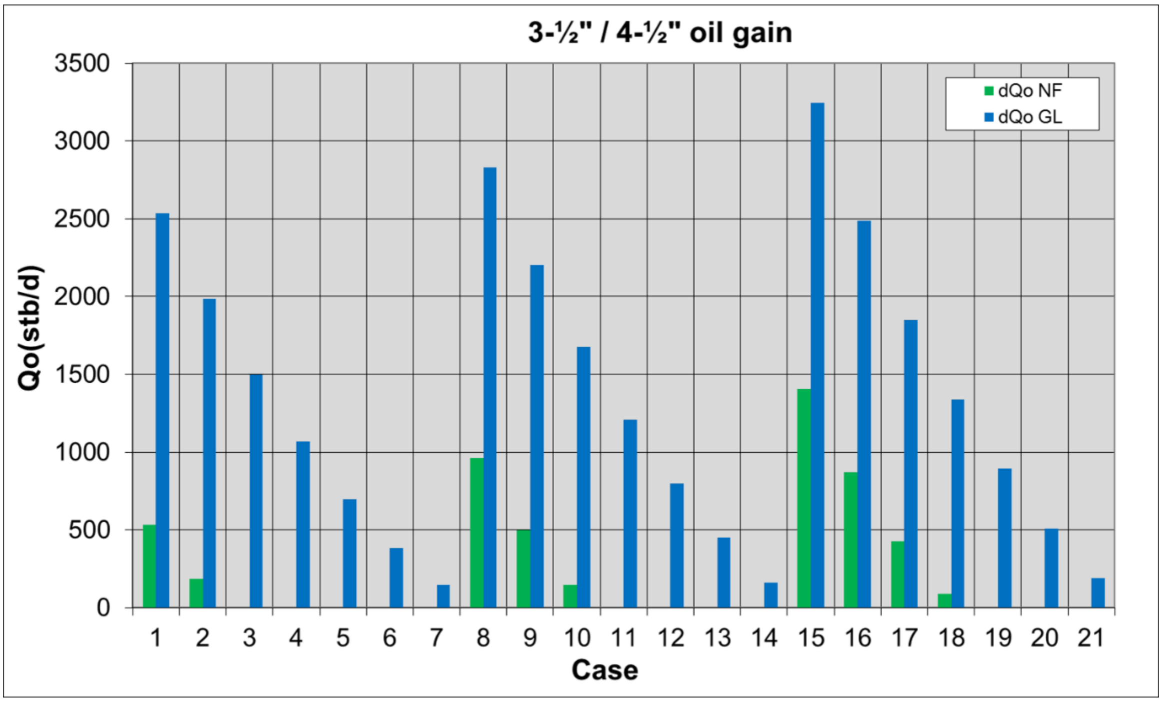

Figure 17: Tubing Size Comparison

Figure 18 shows the deliverables at this step. In this example the operating points along the entire length of the well, at different times in the life of the well are superimposed on a flow regime map.

The key here is to ensure that the predicted flow regimes remain out with the critical ‘heading zone’ along the length of the completion throughout the well life cycle. In the below figure NLV and NGV refer to the Liquid velocity number and the gas velocity number respectively with these being functions of the superficial gas and liquid velocities in addition to the surface tension and density.

This information provides our clients with further assurance that the proposed design is robust throughout the life of well.

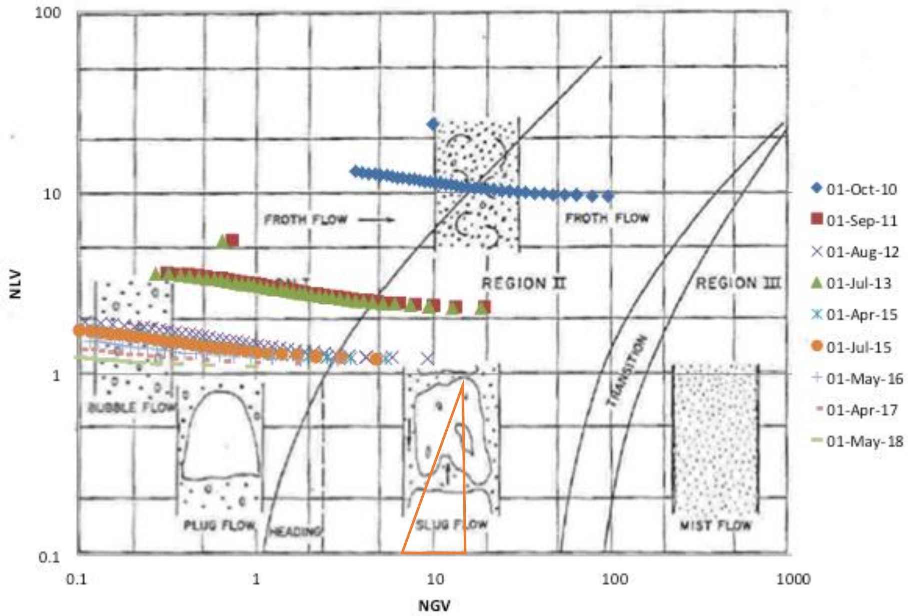

Figure 18: Flow Regime Profile

Step 7: Check Valve Chattering

The unique architecture of the PTC gas-lift check valves, delivers significant functionality and reliability benefits. These benefits are fully described in a separate white paper [2].

A key benefit is that the propensity for check valve chattering is significantly reduced. In PTC gas lift valves the orifice is connected to the check dart, which enables the pressure drop over the orifice to be used to push and hold the check valve open.

Nevertheless, in cases where the differential pressure across the orifice is low (e.g. at very low lift gas rates) chattering can still occur.

To mitigate this, the PTC proprietary software is used to check all of the design cases to identify the conditions under which chattering could occur.

Figure 19 shows the chatter zone superimposed on the orifice performance diagram. As long as the valve is operated above the chatter envelope, valve reliability will be assured.

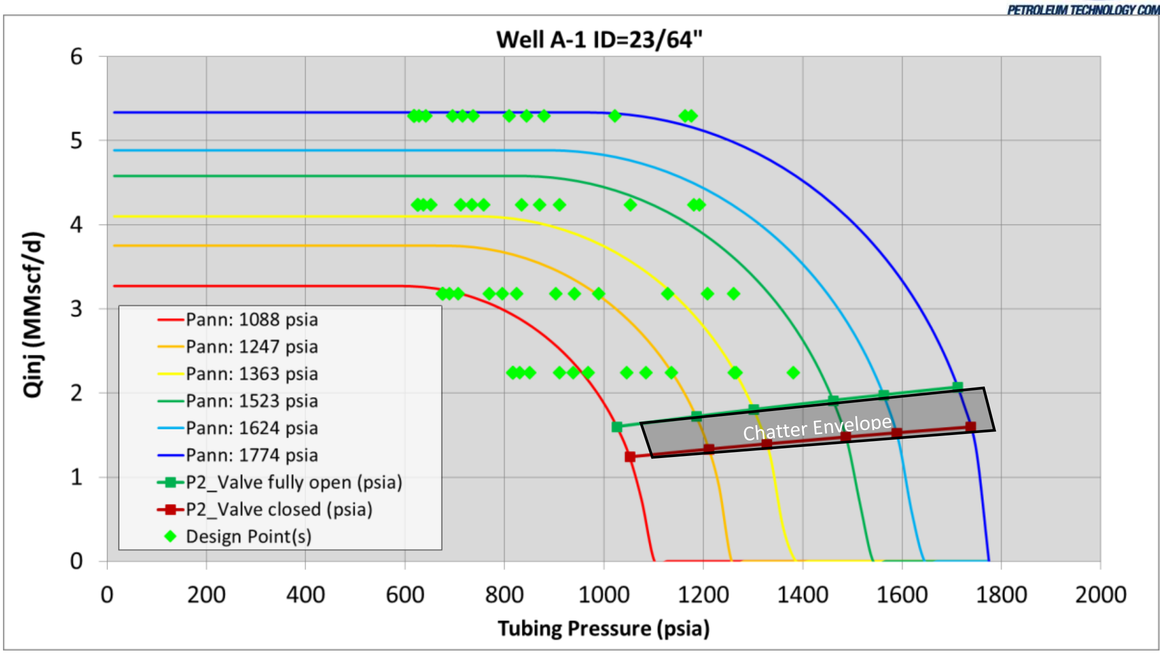

Figure19: Orifice Chattering Envelope

This provides our clients with further assurance regarding the reliability of their gas-lift equipment. Again we understand this level of assurance to be unique in a routine gas-lift design activity set.

Step 8: Mineral Scale Formation

Following the onset of water production, mineral scale deposition is a common challenge in oil (and gas) wells worldwide.

The flow wetted parts of PTC's gas-lift valves (latch and nose) are coated with a hydrophobic material, to reduce to propensity for scale adherence. We can also provide a special scale mitigation gas-lift valve, DuraLift. DuraLift was designed to eliminate the potential for any produced water entering the gas-lift valve (due to turbulence or following shut in due as water segregates within the well).

To help our clients make decisions regarding the use of the DuraLift, it is essential to be able to predict the likelihood of scale precipitation at the gas-lift valve setting depths.

PTC's proprietary gas-lift design toolkit, predicts the propensity for deposition of the most common scale species, at valve depths, throughout the field life cycle.

The simulator takes account of predicted pressure and temperature profiles along the wellbore, and the compositions of formation and injected water as well as the CO_2 content in produced and injected gas. Joule Thomson cooling effects are also accounted for (with 3 temperature models available).

An example of the deliverables from this step are shown in Figure 20, where the propensity for Calcium Carbonate scale is illustrated over the various design cases.

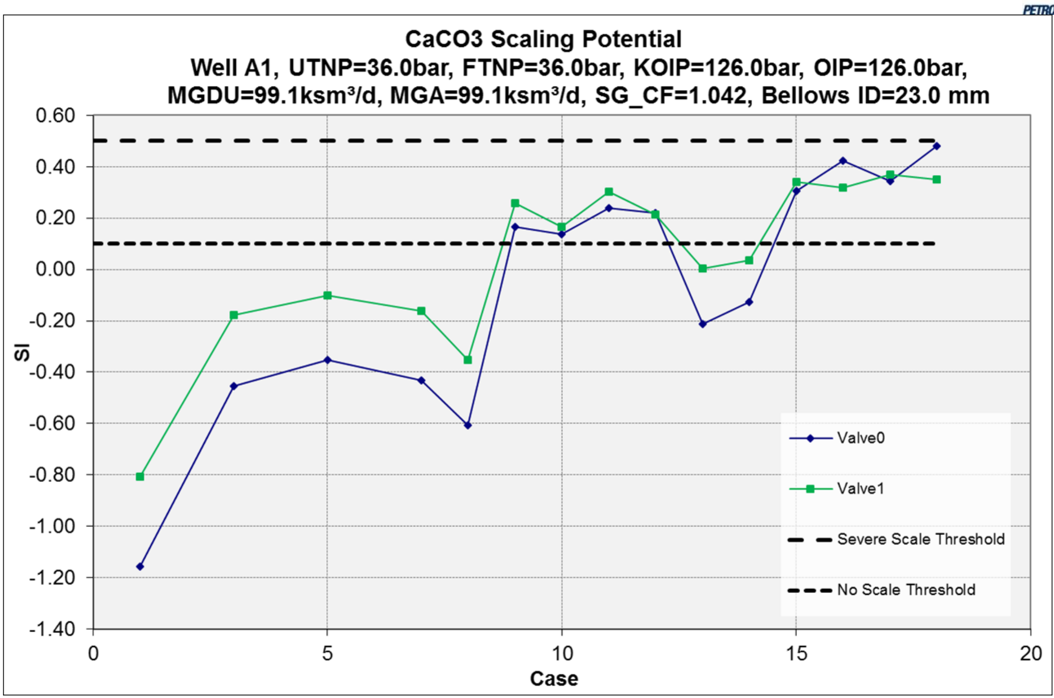

Figure 0: $CaCO_3$ Scaling Tendency at Valve

It can be seen that for design cases 1 -8 and 13 -14, no scale is predicted at the locations of the 2 gas-lift valves. For the other design cases the potential for scaling does exist.

This information helps our clients to plan any scale mitigation strategy, e.g. the use of the DuraLift gas-lift valve or in severe cases possibly scale inhibitor delivery via chemical injection.

N.B. PTC also provide unique chemical injection valves and proprietary software to model chemical injection systems to help assure life cycle effectiveness and reliability [3].

Step 9: Shearable Valve Shear Pin Ratings

PTC offer shearable options for operating and (uniquely) unloading valves. These valves behave as dummy valves until they are sheared open, after which time they operate in the same manner as conventional valves.

They offer the benefit that there is no need to install and retrieve dummy valves for annulus pressure testing after installing the completion. This can save a few days commissioning time. PTC offer both annulus and tubing shearable valve options.

The mechanism is a simple shear pinned rod, which holds the check valve closed when annulus pressure is applied. For single valve applications, additional pressure applied via the annulus, provides the force to shear the pins. For multi-valve applications (e.g. wells with unloading valves) the mechanism employs an atmospheric chamber. In this case, pressure applied via the tubing provides the force required to shear the pins.

In either case it is necessary to carefully select the shear pin rating. PTC's proprietary shear module software is used for this purpose. An example of the deliverables from this stage are shown in Figure 22. Here we plot the packer setting and pressure tests values at the valve setting depth and superimpose the shear pin test data results (for primary and back up valves).

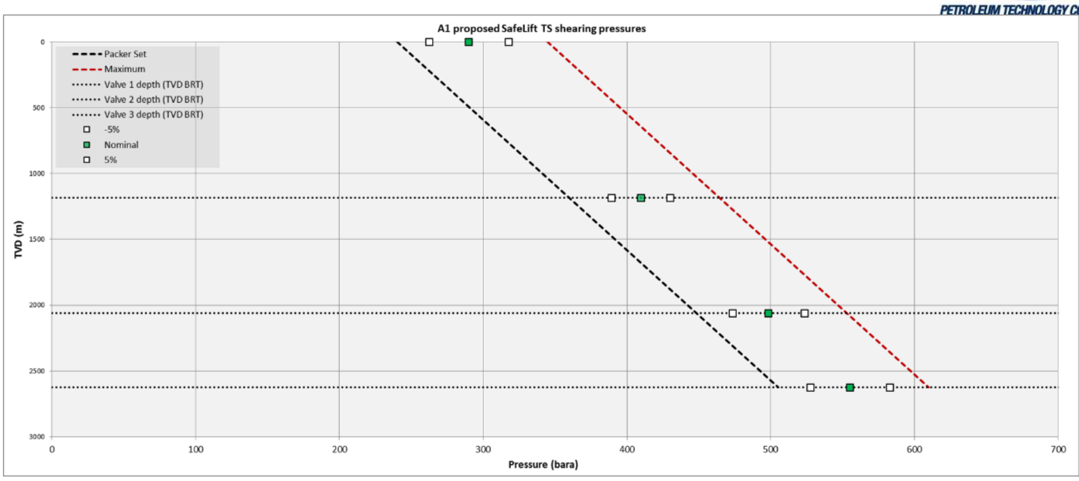

Figure 2: Gas-Lift Valve Shear Pin Window 006D **or the maximum allowable pressure.**

PTC work with our clients to develop a programme that can accommodate all of the completion objectives. This gives our clients further assurance that the well commissioning will be trouble free.

Step 10: Unloading Schedule

The most challenging duty for any gas-lift valve is during the initial unloading of the well. This is when completion brine (and any associated drilling debris) passes through the valve from annulus to tubing. It is therefore critical to control liquid velocities, to ensure that erosion is avoided during unloading.

The PTC proprietary software toolkit includes a pseudo transient simulator, which provides our clients with guidance in this respect. The deliverable from this stage is shown in Figure 23.

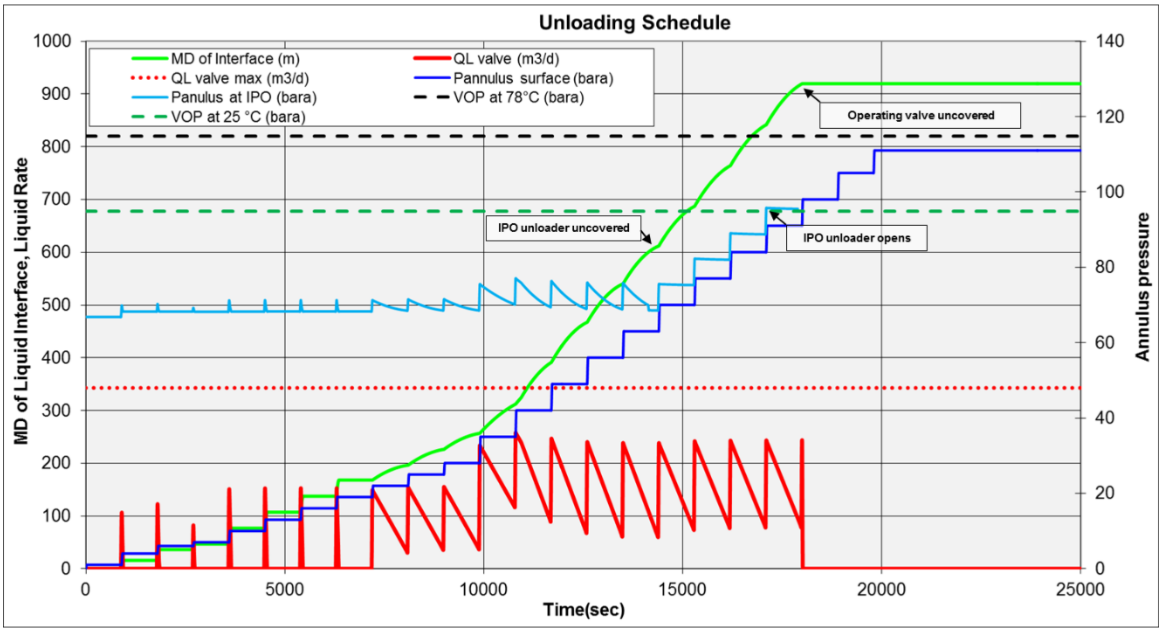

Figure 3: Unloading Schedule

The approach is that the unloading rate will be controlled using annulus pressure (narrow blue line). If the annulus pressure is increased in the time increments shown, then the liquid rate (thick red line) will be less than the maximum allowable liquid rate (dotted red line). This advice provides our clients with further assurance that the gas-lift valves will not be damaged during the well commissioning process.

Conclusions

A uniquely rigorous gas-lift design process has been developed by Petroleum Engineers for Petroleum Engineers. It provides our clients with:

- The information necessary to select the optimum number of gas-lift valves to use in any given well along with the optimum valve spacing
- Assurance that the design is flexible and robust across all anticipated lifecycle operating conditions and under all anticipated operating scenarios
- Comfort that the likelihood of multi-pointing or being unable to reach planned lift depths is minimised
- Assurance that check valve chattering will be avoided
- Assurance that the valves will not be damaged during unloading
- Indication of mineral scale formation potential at the gas-lift valves

References

1. Enhancing Gas Lifted Well Production. PTC White Paper.

2. Enhancing Gas Lifted Well Integrity. PTC White Paper.

3. Chemical Injection Systems. PTC white paper.

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